Public Service Commission of Wisconsin
Direct Testimony of Justin Adams
Division of Energy Regulation and Analysis

Wisconsin Public Service Corporation
Docket 6690-UR-127

September 9, 2022

Q. Please state your name, business address, and occupation.

A. My name is Justin Adams, and my business address is the Public Service Commission of Wisconsin (Commission), 4822 Madison Yards Way, Madison, Wisconsin 53705. I am employed by the Commission as a Public Utility Financial Analyst in the Division of Energy Regulation and Analysis.

Q. Please describe your educational and professional background.

A. I have an undergraduate degree in Psychology from Hanover College and Master's level coursework in Experimental Psychology, with an emphasis on statistics, from the University of Dayton. I have also attended Utility Rate School sponsored by the National Association of Regulatory Utility Commissioners. I began working for the Commission in September 2019.

Q. What are your major job responsibilities?

A. I work on financial and economic issues in the electric and natural gas area. My responsibilities include analyzing and processing securities applications, and analyzing and recommending rates of return, interest rates, and capital structure, as applicable, for rate cases and financing applications. I also evaluate and analyze risk management plans.

Q. What is the purpose of your testimony?

A. I will be presenting testimony on the rate of return component of the revenue requirements for Wisconsin Public Service Corporation (applicant). This includes

examination of the utility capital structure, the cost of debt, and the required return on common stockholders' equity. As part of this examination, I prepared one exhibit. Ex.-PSC-Adams-1 provides financial data related to applicants' capital costs in the 2023 test year, and consists of 12 schedules. I also briefly address the applicant's dividend restrictions, fuel hedging cost considerations, and coal plant retirements in this narrative.

Q. Please summarize your testimony.

A. First, I discuss the adjustments that were made to the applicant's financial and regulatory capital structures. This includes an analysis of off-balance sheet obligations. Second, the historic and current financial market trends along with appropriate short- and long-term debt costs are discussed. Third is a discussion of the return on equity (ROE). The applicant has proposed an ROE of 10.00 percent, which is the applicants' currently authorized ROE. I estimate a range for the ROE of 8.46 percent to 9.79 percent, and instructed Commission audit staff to use 9.80 percent as the point estimate for calculating the revenue requirement. This represents a more gradual 20-basis point reduction in the applicant's ROE from their last rate case in docket 6690-UR-126.

Capital Structure

Q. What procedure did you follow in estimating an overall cost of capital for the applicant?

A. The procedure involves several steps, the first of which is selecting an appropriate capital structure. The capital structure is the proportion of capital utilized in the corporation from common stock, preferred stock, and long- and short-term debt. The capital structure is significant with respect to the overall cost of capital and the ability of the applicant to hold and attract capital.

The second step is to estimate the cost levels of the various components of capital. In general, this step is designed to infer current investor expectations of capital costs for the applicant during the test year. The expected capital costs defined would fairly compensate the applicant for its interest costs during the test year and would provide WEC Energy Group, Inc. (WEC), the applicant's equity owner, with a return that fairly compensates it for time preference and investment risk, and enables the applicant to preserve and attract capital in its long-term operations.

Specifically, this step first examines historical and recent trends in interest rates and utility capital market costs in an attempt to assess current investor expectations based solely upon the historical data. Further analysis involves examination of inflation and interest rate forecasts, theoretical capital cost projections, and potential economic conditions to infer additional information regarding investor expectations. The final analysis requires an assessment of investment risk specific to the applicant during the test year and how that risk is factored into current investor expectations.

The final step is to calculate the weighted cost of capital, which is developed in this testimony and the associated exhibit.

Q. Explain in more detail how you conducted your analysis of capital structure for the applicant.

A. In determining the appropriate capital structure for the applicant, the Commission considers the impact on customer rates and the utilities' creditworthiness and financial flexibility at various proportions of common equity. As a public utility, the applicant's financial strength and ability to attract capital at a reasonable cost is critical to providing a safe and reliable service. A weak financial position would increase the cost of debt and

equity, which in turn would ultimately increase the overall revenue requirements borne by customers.

Assessing the reasonableness of the applicant's capital structure depends upon several important principles.

First, capital structure decisions must be based on the utility's needs, not the needs of the non-utility operations of the holding company.

Second, the capital structure should provide adequate flexibility for the applicant to support proper utility investment now and in the future.

Third, it should support a corporate dividend policy generally consistent with typical peer regulated utility dividend practices, as long as dividend payments do not cause the common equity ratio to decline below the authorized common equity level.

The identification of utility needs goes beyond foreseeable needs, and the applicant must have a reasonable degree of flexibility to finance both foreseen and unforeseen capital requirements. Under Wis. Stat. § 196.795(5), a utility's capital needs must take precedence over non-utility needs if ratepayers are to be protected:

> (f) No nonutility activity of any holding company or nonutility affiliate may be subsidized materially by the consumers of any public utility affiliate with which the holding company or nonutility affiliate is in the holding company system. No public utility activity of any holding company or public utility affiliate may be subsidized materially by the nonutility activities of the holding company or any of its nonutility affiliates.
>
> (g) No holding company system may be operated in any way which materially impairs the credit, ability to acquire capital on reasonable terms or ability to provide safe, reasonable, reliable and adequate utility service of any public utility affiliate in the holding company system.

Q. Please explain Schedule 1 of Ex.-PSC-Adams-1 with respect to the capital structure of the applicant.

A. The bottom portion of page 1 of Schedule 1 shows the utility regulatory, or rate-making capital structure I estimated for the test year ending December 31, 2023. In this case the utility regulatory capital structure consists of 53.40 percent common equity, 46.14 percent long-term debt, and 0.46 percent short-term debt. The utility common stock equity was developed by removing from the applicant's equity, as reported on its balance sheet, any non-utility investments on which ratepayers should not pay an equity return or other equity adjustments for ratemaking purposes. The adjustments may be positive or negative.

The top portion of page 1 shows the financial capital structure consisting of 53.00 percent common equity, 45.36 percent long-term debt, 1.19 percent equivalence for off-balance sheet obligations, and 0.45 percent short-term debt. The inclusion of off-balance sheet obligations in the financial capital structure is consistent with the Commission's previous rate case decisions for large Wisconsin investor-owned utility.

Q. What is the target level for the applicant's common equity?

A. In previous rate cases, the Commission has used 52.50 percent common equity, on a financial basis, for the applicant's capital structure. The applicant has requested a 53.00 percent common equity layer in the current docket. I did not adjust this requested equity layer for the revenue requirement in this docket.

Off-Balance Sheet Obligations

Q. Please discuss in general the imputation of debt equivalents for off-balance sheet obligations.

A. The Commission has devoted substantial efforts to calculate an off-balance sheet debt equivalence and use that calculation in determining an appropriate capital structure. The

Commission uses these calculations to measure the obligations and accurately moderate the utility's capitalization to maintain the appropriate financial leverage.

There are cost implications to protecting the applicant's credit in light of the off-balance sheet debt equivalent. For every dollar of off-balance sheet debt equivalent the applicant accepts, 53 cents[1] of rate-base related debt must be converted to equity. Since equity is more expensive than debt, this comes at a cost to ratepayers, as shown on page 2 of Schedule 1 of Ex.-PSC-Adams-1. While it is appropriate that ratepayers compensate the investors for the additional equity needed to maintain financial health, the measurement of the risk is subjective, and ratepayers should not pay more than necessary.

Dividend Restrictions

Q. Do you propose any changes to the applicant's dividend restriction?

A. In previous dockets, the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices. In docket 6690-UR-124, the Commission adopted the following dividend restrictions for the applicant:

> WPSC may not pay dividends in excess of the amount forecasted in this case if those dividends cause the average annual common equity ratio, on a financial basis, to fall below the test-year authorized level of 51.00 percent.
>
> The determination of whether the payment of dividends, over and above a typical or normal dividend, is appropriate can only be made at the end of the test year. Therefore WPSC shall wait until the end of the test year to pay additional dividends to the parent. Additional dividends may only be paid if their payment will not cause the common equity ratio, on a financial basis, to fall below the test-year authorized levels.

[1] This amount would vary depending on the target equity percentage.

I propose the dividend restriction be revised to remain consistent with the Commission's determinations for the applicant's common equity ratio, as measured on a financial basis.

Short- and Long-Term Debt Costs

Q. What have been the long-term and recent trends in interest rates and utility borrowing costs?

A. Information about historical annual and monthly long-term and intermediate-term interest rates is presented on Schedules 5 and 6 of Ex.-PSC-Adams-1. The data presented covers interest rates incurred on U.S. government debt instruments, and also specific interest rates incurred on debt instruments issued by public utility companies. The annual data listed covers a 40-year period (1982 through mid-year 2022). Yield spreads, or premiums, are also shown. They provide a measure of the risk premium required by debt investors for companies having financial characteristics that lead to lower bond ratings, and also outline compensation required by debt investors for default risk.

In general, as seen on page 3 of Schedule 5, public utility debt costs have declined over the past 40 years but began rising starting in mid-2021.

Q. What are the current default risk premiums required by investors in utility bonds?

A. Pages 1 and 2 of Schedule 5 shows yearly premiums for A-rated utility bonds over 10-year and 30-year U.S. Treasury notes. Spreads are affected by changes in both U.S. Treasury note and utility bond yields. Consequently, recognition also needs to be given to any effects U.S. Treasury yields have on spreads. An increase in spread could be a flight of investment to U.S. Treasury securities rather than an increase in investor-required utility bond yields.

Q. What has been the recent trend in short-term interest rates?

A. Page 1 of Schedule 4 lists recent values for the prime lending rate and the Secured Overnight Financing Rate (SOFR). The London interbank offered rates (LIBOR) were traditionally used in this analysis, but this benchmark was retired in December 2021 and replaced with SOFR. For the purposes of the current analysis and narrative, SOFR and LIBOR data are used interchangeably. As of the first week of June 2022, the prime interest rate was 4.00 percent, and SOFR rates were at 1.12 percent to 1.63 percent. The applicant's commercial paper is currently rated "A-2" by S&P and "P-1" by Moody's.

Q. How do current and forecasted rates of inflation compare to levels experienced historically?

A. Schedule 7 of Ex.-PSC-Adams-1 provides historical and projected inflation rates as measured by changes in the Consumer Price Index. The schedule shows the annual inflation rates from 1964 through June 2022. The historical data is important to the extent investors use it in forming expectations of capital costs over the test-year period. Inflation projections for 2022 and 2023 from *The U.S. Economic Outlook* (Global Insight) and from *Blue Chip Economic Indicators* are shown, as well as my inflation estimates, which are 7.20 percent for 2022 and 3.20 percent for 2023.

Q. Have you reviewed any forecasts of interest rates for the test year?

A. Yes. Schedule 6 of Ex.-PSC-Adams-1 shows interest rate forecasts, which I reviewed in estimating the applicant's cost of capital for the test year. Two different forecasts are presented. First, data from the June 2022 *Blue Chip Financial Forecasts* is provided. The June data was used in developing the interest rate premium model, which is discussed later in this testimony. Second, data from the July 2022 *Blue Chip Financial*

Forecasts is presented. After comparing macroeconomic forecasted interest rates against those forecasted by the utility, staff chose to accept the lower rates forecasted by the applicant for the test year.

Q. What is the embedded cost of short-term debt capital of the applicant for the purposes of this proceeding?

A. The composite cost of embedded short-term debt for the applicant is 5.34 percent for the test year. The average forecasted amount of short-term debt outstanding is $21,600,000 for the test year. The applicant notes that this short-term debt cost and rate include expenses associated with the short-term debt credit facility and rating-agency fees (both fixed and variable). The total cost of those line-items is $817,000 for the test year. Ultimately the Commission could consider disallowing a return on the expenses associated with the short-term debt credit facility and rating-agency fees as these could be considered pass through costs. At the embedded short-term debt cost rate for these items, the disallowance would amount to $43,628.

Q. What is the applicant's embedded cost of long-term debt capital for the purposes of this proceeding?

A. The composite cost of embedded long-term debt for the applicant is 4.00 percent. The average forecasted amount of long-term debt outstanding is $2,100,00,000 for the test year.

The applicant's long-term cost rate reduction since their last rate case is noteworthy. In docket 6690-UR-126 the applicant's cost of debt was 4.37 percent on $1,657,954,000. Through strategic refinancing, the applicant has materially reduced their overall cost of long-term debt by 37 basis points in that timeframe. Since this is the first

time the Commission is reviewing the full capital structure of the applicant since 6690-UR-126, the Commission could consider a commensurate reduction in the applicant's return on equity for the test year to offset the reduced debt expenses incurred by the applicant during that intervening period.

Q. How might rising interest rates affect the creditworthiness of the applicant?

A. The applicant's long-term issues are currently rated "A-" by S&P and "A2" by Moody's. The applicant's rating outlook is rated as "Stable" by both agencies. The stability of this rating is largely driven by the applicant's ability to manage operating costs and the relative supportiveness of the regulatory environment in Wisconsin.[2],[3]

Although rising interest rates will affect future debt issuances by the applicant, the applicant currently has no filed issuances forecasted in the test year. A change in the creditworthiness outlook of the applicant is not likely to have an impact on the embedded long-term debt costs in the test year for that reason. In Schedule 11 of Ex.-PSC-Adams-1 I display the debt yield curve, as of June 2022, for 'A' and 'AA' rated corporations, as well as for a composite of all rated utilities. Although current forecasts from the applicant price their debt securities closer to an A-rated Corporation, an erosion of the applicant's creditworthiness leading to a credit downgrade would likely place the applicant on a similar footing as the composite of all rated utilities for pricing debt securities in the future.

Return on Equity

Q. Please describe how you estimated the appropriate return on equity for the applicant.

[2] From pg. 2 of Ex.-WPSC-Shipman-3
[3] From pg. 3 of Ex.-WPSC-Shipman-4

A. In estimating the expected test-year equity cost, I took into consideration various theoretical relationships that provide information regarding the equity return expected by investors in the applicant's common stock and acknowledged by other utility jurisdictions nationally. I also considered current and expected interest rates, the expected investment risk associated with holding the applicant's securities during the test-year period, and the overall state of the economy.

Q. What information did you use in estimating the appropriate return on equity for the applicant?

A. I used a discounted cash flow (DCF) model, shown on Schedule 8 of Ex.-PSC-Adams-1. I have also provided an interest rate premium analysis, shown on Schedule 10. Finally, I computed a composite ROE range for the regulated utilities of all the peers chosen in the DCF analysis. To balance the aggregate ROE range from these models, I used point comparisons of average ROEs for vertically integrated utilities nationally (last four fiscal quarters) and large Wisconsin investor-owned utilities (last three years) separately. The table below summarizes my findings.

WPSC ROE Model Summary		
	ROE (%)	
Model	Low	High
Discounted Cash Flow	5.85%	8.26%
Discounted Cash Flow (90 Day)	5.58%	7.94%
S&P National Averages (1 year)	9.47%	
Wisconsin Average (3 years)	9.98%	
Interest Rate Premium	10.65%	11.12%
DCF Peers	9.20%	11.95%
Average	**8.46%**	**9.79%**
	Midpoint	9.12%

In previous cases, the Commission has indicated that market models should not be applied mechanistically, but that they should be used as one piece of information in determining the appropriate return on equity. Furthermore, the proper use of capital cost

models requires an examination of the assumptions necessary for the modeled theoretical relationships to hold. In cases where the assumptions seem unrealistic, the model results should be interpreted accordingly. An attempt should be made to identify assumptions necessary to estimate input parameters of the models, and the appropriateness of those assumptions should be evaluated.

Q. Please discuss the DCF models underlying the returns in Schedule 7.

A. The DCF model begins with the principle that the current value of an investment should be equal to the discounted value of future cash flows to be received from that investment. From a theoretical perspective, it relies upon a relatively straightforward concept that applies to most investment types, and across all industries. An investor knowing the current divided, the rate of growth for the dividend, and his or her required return, can calculate the price at which he or she will purchase the security. The model can be described as follows:

$$P_0 = D_0 + \frac{D_0(1+g)^1}{(1+r)^1} + + \frac{D_0(1+g)^2}{(1+r)^2} + \cdots + \frac{D_0(1+g)^\infty}{(1+r)^\infty}$$

P_0= current stock price

D_0= current dividend payment

g= dividend growth rate

r= required return on equity

Conversely, knowing the purchase price of the security, its current dividend, and the rate of growth of the dividend, allows an investor to calculate the required return.

A DCF model's growth rate can be based on dividend growth rates or earnings growth rates. The DCF can be based on a constant growth model, where it is assumed that the current growth rate would continue indefinitely, or use multiple stages, which

recognize that the current growth rate may not be obtainable indefinitely or that the growth rate may currently be adversely affected.

Q. What discounted cash flow models did you use for Schedule 8?

A. The data shown in Schedule 8 is based on earnings growth. I performed the analysis using data sets representing stock valuations as of market close on June 30, 2022, and a second analysis using average stock valuations for the 90-day period ending June 30, 2022. The results are from a single-stage DCF model and two two-stage models. The two-stage models assume that the current earnings growth rate continues for 5 and 10 years, respectively, and then reverts to a terminal growth rate of 2.50 percent.

Q. Discuss the selection of the Combination Utility proxy group.

A. For the purposes of estimating a reasonable ROE of the applicant, I established a proxy group of combination regulated electric and gas utilities. I began with the S&P Capital IQ Pro Utility Industry data set and applied the following screening criteria:

1. Must be publicly-traded on a U.S.-Based exchange;
2. Must be subcategorized as an Electric, Multi, or Gas Utility;
3. Must be currently paying common dividends;
4. Must have investment grade long-term issuer ratings;
5. Must derive at least 70 percent of operating income from regulated electric or gas utility operations, as reported in its 2021 annual report on form 10-k;
6. Must derive at least 50 percent of regulated utility operating income from electric utility operations and at least 10 percent from gas utility operations, as reported in its 2021 annual report on form 10-k;
7. Must own regulated electric generation assets;

8. Must have at least two published sell-side analyst estimates for the next fiscal year;

9. Must not have been involved in a significant merger, acquisition, or other transformative transaction underway during the period of the analysis.

Q. Did you include WEC in your analysis?

A. No. It is important for the subject company to be excluded from the proxy group analysis to avoid circular logic.

Q. What is the composition of your Combination Utility proxy group?

A. The proxy group utilized in the analysis summarized on page 1 of Schedule 8 includes the following:

Company	Ticker
Avista Corporation	NYSE:AVA
Black Hills Corporation	NYSE:BKH
CMS Energy Corporation	NYSE:CMS
MGE Energy, Inc.	NasdaqGS:MGEE
NiSource Inc.	NYSE:NI
NorthWestern Corporation	NasdaqGS:NWE
Sempra	NYSE:SRE
The Southern Company	NYSE:SO
Xcel Energy Inc.	NasdaqGS:XEL

Q. What were the findings of your Combination Utility DCF analysis?

A. As summarized on pages 1 and 2 of Schedule 8, the valuation levels and consensus estimates at the time of the analysis are indicative of an approximate range of expected annual returns of 5.85 percent to 8.26 percent.

Q. Did you perform any sensitivity analysis on the DCF model?

A. Yes. The selection of the terminal growth rate and assumed required return are important. Valuation levels during the model test periods suggest that if the assumed

terminal growth rate is increased to 2.50 percent, the implied market required rate of return would range from 5.45 percent to 7.97 percent. I also calculated the theoretical terminal growth rate required to support the same valuation levels if the required rate of return equaled 9.80 percent. Under that assumption, the models indicate a terminal growth rate of 5.26 percent to 6.41 percent. The results of the sensitivity analysis are shown on page 1 of Schedule 8.

Q. Describe the theoretical underpinning of the Interest Rate Premium model.

A. Similar to yield spreads for debt securities, insights can be gained through analysis of authorized rates of return relative to prevailing debt security yields at the time rate case decisions are announced. Studying the historical correlations and spreads between authorized ROEs, equity market valuations, and various interest rates on debt securities can provide useful insights in the analysis of required returns. The data provides an additional measure of the risk premium required by equity investors in comparison with other investment options with different business models, regulation, credit ratings, and other financial characteristics.

Q. Describe the key observations from your Interest Rate Premium analysis.

A. Schedule 9 presents an analysis of average authorized ROEs for electric and natural gas utilities based in the U.S. since 1985 and compares those authorized returns to the average yield on various types of debt securities. For the period of January 2012 through June 2022, the simple average authorized ROEs for vertically integrated regulated electric utilities was 702 basis points over 30-year U.S. Treasury bond yields, 767 basis points over 10-year U.S. Treasury note yields, 600 basis points over AA-rated utility bond yields, and 523 basis points over Baa-rated seasoned corporate bond yields.

With the exception of 10-year Treasuries, authorized ROE spreads across each of the debt securities analyzed have followed a trend of widening materially as long-term interest rates declined. In other words, reductions in authorized ROEs have not matched the pace or magnitude of the decline in interest rates over the past 30 years. Recognizing the potential impact of the continued downward trend on the model output, I calculated the weighted average ROE spreads relative to each of the debt securities over the past four years, with the most recent year weighted at 40 percent; the previous year weighted at 30 percent; 20 percent, and 10 percent weights, respectively, for the least recent two years.

Q. What were the conclusions from your 10-year Interest Rate Premium analysis?

A. I applied these data to an analysis of historical yield spread relationships between the various debt securities, coupled with forecasted yields on debt securities during the 2023 test year based on June 2022 forecasts from *Blue Chip Financial Forecasts* and *IHS Global Insight*. Applying the 10-year simple average ROE spreads for vertically integrated electric utilities to the forecasts supports an ROE range of 10.52 percent to 11.07 percent. Applying the four-year weighted average ROE spreads for vertically integrated electric utilities to the forecasts supports an ROE range of 10.65 percent to 11.12 percent.

Q. Are there any caveats concerning the results in Schedule 9?

A. Yes. The estimated returns are based on premiums over debt securities relative to past authorized returns. These premiums are not necessarily reflections of market required premiums at this point in time, but rather reflect the premiums based on past Commissions decisions across the country.

Q. What rates of return has the Commission authorized in recent years for large investor-owned utilities?

A. Results of Commission orders with respect to cost of capital and rates of return from 1987 to 2021, for major Wisconsin utilities, are summarized on page 4 of Schedule 9 of Ex.-PSC-Adams-1. As part of my modeling in this docket, I calculated an average ROE for large Wisconsin investor-owned utilities over the last three years. The average ROE for this group was 9.98 percent which is 18 basis points above the staff recommended ROE for the applicant in this docket.

Q. What returns have been authorized by other state utility commissions?

A. Page 1 of Schedule 9 of Ex.-PSC-Adams-1 provides data on the average regulatory allowed returns for electric utilities and natural gas utilities since 1980. I included an average ROE from the last 4 fiscal quarters of data provided on vertically integrated utilities nationally in my modeling. The average return for vertically integrated utilities, nationally, for the last 4 fiscal quarters is 9.47 percent.

Additionally, in Schedule 12 I reviewed the most recently authorized returns for all operating utilities that were included as peers of WEC in the DCF analysis. The average return for this group of operating utilities was 9.79 percent with an average WACC of 7.21 percent. Two caveats are noteworthy about this data. First, not all data was available in the S&P Capital IQ Pro platform for all operating utilities in this peer group. Missing data points were removed from the calculation of these averages. Second, some jurisdictions allow for cost recovery mechanisms in the form of limited-issue riders that can materially change an operating utility's effective return. No attempt was made to interpolate the impact of limited-issue riders from these jurisdictions.

Q. Describe Schedules 2 and 3 of Ex.-PSC-Adams-1.

A. Schedule 2 contains calculations of the WACC and economic cost of capital for the applicant. When a 9.80 percent ROE is applied, the WACC and economic cost of capital are 7.09 percent and 9.05 percent, respectively. The bottom portion shows the times interest coverage using the various cost estimates and the indicated regulatory capital structure. A return of 9.80 percent on common stock equity would result in pre-tax interest coverage of 4.87 times.

Schedule 3 contains a sensitivity analysis of each operating component of the applicant's regulated operating utility (electric and gas) in Wisconsin and the relative impact of varying capital structure and ROE estimates on the applicant's revenue requirement for the test year.

Q. What might the Commission consider for a reasonable authorized rate of return on utility common equity for the applicant in the test year?

A. Based on the financial information provided by the applicant in their application and available macroeconomic and jurisdictional data as of June 2022, the Commission may wish to consider the aggregate average of the ROE ranges staff has computed of 8.42 percent to 9.79 percent to be reasonable for the test year. Commission staff used 9.80 percent as the point estimate for calculating revenue requirement in this case. Although this point estimate is above the aggregate range computed by Commission staff, the Commission's past deference to gradual increases or decreases in utility returns may be a reasonable consideration in this case.

Fuel Cost Plan Hedging

Q. How has the rising price of natural gas affected the applicant's fuel hedging strategies.

A. As natural gas prices and supply bottlenecks began to rise in 2021, the applicant limited purchasing 2023 financial hedges for electric generation against these prices for all of 2021. The applicant returned to purchasing 2023 hedges in the first quarter of 2022 after an internal approval of the applicant's hedge plan for 2023. As a result, it is possible that the applicant's customers could be exposed to increased upward pricing pressures. Given that we do not know what the end results of the applicant's hedging strategy as it relates to the purchase of 2023 financial hedges may be, the Commission could consider requiring the applicant to address this in its 2023 fuel reconciliation filing. Otherwise, the Commission may wish to consider imputing a reduction in the forecasted cost of natural gas for the test year due to this reduction in hedging volume for the test year.

Coal Plant Retirement

Q. What impact will change to the retirement schedule for Columbia Unit 1 have on applicant's test year filing.

A. As publicly announced, the retirement of Columbia Unit 1 will be pushed back outside of the applicant's test year in this docket. The applicant has a 27.50 percent ownership stake in the Columbia Energy Center. The applicant requested a limited electric rate reopener for 2024 in part to account for reduced operation and maintenance costs associated with this retirement.

Q. Did you consider whether parties could potentially benefit from other financial arrangements regarding the retirement of Columbia Unit 1?

A. Stranded assets have presented in concerns in prior Commission proceedings. In some cases, as in docket 6680-UR-123 (PSC REF#: 427760), settling parties have addressed concerns through the use of earnings sharing mechanism dollars. Securitization was

previously explored by the Commission for this utility in docket 5-UR-109 (PSC REF#: 381305), and was ultimately utilized through a Financing Order in docket 6630-ET-101 (PSC REF#: 400098), to reduce the ratepayer impact of $100 million of undepreciated environmental controls at the Pleasant Prairie Power Plant, in accordance with Wis. Stat. § 196.027. The Commission may wish to consider whether and how such financial arrangements with similar ratepayer benefits might be used to allow the applicants to recover a reasonable guaranteed return on undepreciated assets, while reducing the burden on their ratepayers for those same assets in the face of market-wide rising interest rates and inflation. The Commission could consider requiring something similar to what it required Wisconsin Power and Light Company to do in docket 6680-UR-123, in which it required the utility to file, in its next rate case, an analysis of alternatives regarding the recovery of the remaining useful life of certain identified generating units, and any other generating units proposed to be decommissioned prior to the end of the facility's useful life.

Q. Does this conclude your direct testimony?

A. Yes, it does.

JA:dsa:jlt:DL:01908823